Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

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May 18, 2009

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The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
Kekuanaoa Building, 1st Floor
465 South King Street
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2008-0274 – Decoupling Proceeding
<u>HECO Companies' Responses to Information Requests</u>

The HECO Companies hereby file responses to the information requests ("IRs") prepared by the Commission's consultant, the National Regulatory Research Institute, and submitted to the Companies on April 30, 2009.[1] For reference purposes, the Companies have renumbered the twelve IRs as PUC-IRs 27 to 38, following in sequential order from the set of 26 IRs submitted by the Commission to the HECO Companies and the other Parties on March 5, 2009.

Enclosed for filing are the HECO Companies' responses to PUC-IRs 27 to 32, and 36 to 38. Under separate cover, the Companies are requesting the Commission's approval for an extension, until Tuesday, May 19, 2009, to file responses to PUC-IRs 33, 34, and 35.

Very truly yours,

Enclosures

cc: Division of Consumer Advocacy
Hawaii Renewable Energy Alliance
Haiku Design and Analysis
Hawaii Holdings, LLC, dba First Wind Hawaii
Department of Business, Economic Development, and Tourism
Hawaii Solar Energy Association
Blue Planet Foundation

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[1] The "HECO Companies" or "Companies" are Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc. and Maui Electric Company, Ltd.

PUC-IR-27

Please refer to your revised response to PUC-IR-14.

a. Confirm that the historical sales for HECO were greater in 2004 than for any of the four years following. If not, please explain.
b. Confirm that on a consolidated basis, for HECO, HELCO, and MECO ("HECO Companies"), for the five years from 2004-2008, that sales were stable except for the drop in 2008. If not, please explain.
c. Confirm that customer growth occurred for each utility and that row 9 is the amount of revenues associated with that growth. If not, please explain.
d. Confirm that for the period 2004-2008, that sales per customer have been declining each year for each utility. If not, please explain.
e. As a comparative reference, please provide a total sales decoupling adjustment and a sales per customer decoupling adjustment for the period of 2005-2008, using 2004 as the base for sales.
f. Please provide the requested responses to rows 35 to 41, recognizing that it is not your proposed decoupling approach.

HECO Response:

As stated in the Companies' response to PUC-IR-14, the HECO Companies completed the requested spreadsheets in that response strictly for illustrative purposes by using information and the same methodology contained in their January 30, 2009 proposal. In response to parts "e" and "f" of this response, the Companies make the same qualifications. The spreadsheets include financial information for future years which is nonpublic information that should not be disclosed publicly as it might trigger requirements under the rules and guidelines of the Securities and Exchange Commission and/or the New York Stock Exchange that information that would be meaningful to investors be released to all investors, if the information is disclosed beyond a limited number of "insiders" (including persons required by agreement to maintain the confidentiality of the information and to use it only for proper purposes), they are being filed under the Protective Order issued on January 9, 2009 in this proceeding. If these attachments are not filed under the Protective Order in this proceeding, the disclosure of nonpublic financial information might trigger disclosure requirements under the rules and regulations of the Securities and Exchange Commission and/or the New York Stock Exchange.

a. Confirmed. As shown on Attachment 1, page 1, of the HECO Companies' response to PUC-IR-14, historical GWH sales for HECO were greater in 2004 than for any of the four years following.

b. Confirmed. On a HECO Companies consolidated basis, for the five years from 2004-2008, total GWH sales were relatively stable except for the decrease in 2008.

c. Yes, customer growth occurred for each utility, and row 9 is the estimate of revenues associated with that growth.

d. Confirmed. As shown on Attachment 1, pages 1 (HECO), 4 (HELCO) and 7 (MECO), of the Companies' response to PUC-IR-14, for the period 2004-2008, sales per customer (GWH per 1,000 customers) have been declining each year for each utility.

e. See Attachment 1, "Response to PUC-IR-27, part e" at the bottom of the spreadsheets, to this response.

f. See Attachment 1, rows 35 to 41 to this response.

Confidential Information Deleted Pursuant To Protective Order, Filed on January 9, 2009.

Attachment 1 contains confidential information and is provided subject to the Protective Order filed on January 9, 2009 in this proceeding.

PUC-IR-28

Please refer to your response to PUC-IR-15.

a. Are the "estimated revenues generated through the proposed RAM" annual incremental revenues or annual revenues above the last rate case (e.g., if the annual incremental revenues were $5, $8 and $6 for three years after the rate case, then the total RAM effect in year three would be $19 or the sum of the three)? If neither, please explain.
b. Would it be correct to conclude that the revenue growth lost to decoupling is equal to PUC-IR Row 9, when Row 8 is negative and to the total of Row 8 and Row 9, when both are positive? If not, please explain how to calculate revenue growth lost to decoupling.
c. Please segregate the decoupling and RAM portions of the proposed adjustments.

<u>HECO Response:</u>

a. The estimated revenues generated through the proposed RAM that are illustrated on Attachment 1 of the response to PUC-IR-15 are annual incremental revenues.

b. Yes.

c. Attachment 1 of the response to PUC-IR-15 segregates the revenues associated with sales decoupling (sum of PUC-IR-14 rows 8 and 9) versus the revenues generated through the proposed RAM (PUC-IR-14, row 31, plus revenue and income taxes).

PUC-IR-29

In the HECO Companies' response to PUC-IR-21, other HCEI costs are mentioned. Please quantify these costs by year

HECO Response:

In PUC-IR-21, HECO Companies mentioned other HCEI costs and responded in part:

> There are many initiatives in the HCEI Agreement [also referred to as the "Energy Agreement"] which will require additional O&M costs not recovered through REIS or other surcharges. These include: 1) labor and non-labor expenses (beyond the costs of outside consultants) to conduct wind studies, negotiate with wind farm developers for power purchase agreements, and the subsequent interconnections; 2) labor and non-labor expenses to analyze solar opportunity, negotiate with photovoltaic developers for power purchase agreements, and the subsequent interconnections; 3) labor and non-labor expenses to accommodate the expected increases in distributed generation; 4) R&D expenses and conversion to biofueling; 5) increased renewable interconnection activities due to the expected adoption of feed-in tariffs and a PV host program; and 6) costs to support the mass transit system and electric vehicles. In HECO's 2009 test year rate case, HECO has included the associated expenses for these activities in the 2009 test year. However, these expenses are tied to the developmental and implementation timelines of these projects and will increase in the later years until these projects are completed.

Many of the initiatives in the Energy Agreement are still in the early stages of implementation, which involve detailed technical, operational, and cost analyses, and feasibility studies. After these preliminary works are completed, internal review and discussion will take place to select the best alternative to move forward, senior management and board presentations (if needed) be made, and internal approvals secured, before the HECO Companies file the applications with the Commission. After the applications are filed, the HECO Companies must abide by the regulatory process which include intervenors and participants to dockets involving these HCEI initiatives to voice their positions. It is only after this regulatory process is completed, that the Commission will approve, modify, or decline the HECO Companies' applications. For those applications which the Commission will approve or modify, the HECO Companies must await the Commission's final decision and orders which will include the appropriate cost recovery mechanism as what components of the projects' costs should be recovered via the Renewable Energy Infrastructure Program/Clean Energy Initiative Surcharge ("REIP/CEI Surcharge),[1] new surcharges (e.g. the Advance Metering Infrastructure ("AMI") Surcharge,[2] existing surcharges, or base rates, and the manner in which the HECO Companies are to recover these projects' costs.

Given the above, at the present time, the HECO Companies have identified the following costs in the following dockets:

1. Docket No. 2008-0083, HECO 2009 Test Year Rate Case;
2. Docket No. 2008-0303, HECO Companies AMI Infrastructure Application;
3. Docket No. 2009-0069, HECO Companies Lifeline Rate Program.

HECO 2009 Test Year Rate Case

In HECO T-1 Rate Case Update, filed December 23, 2008, Docket No. 2008-0083, HECO 2009 test year rate case, pages 11 to 22 discussed additional test year cost estimates due to the signing of the Energy Agreement and its related HCEI implementation studies, and labor and non-labor costs for HCEI initiatives which HECO has cost estimates. HECO T-1 Rate Case Update, Attachment 4, provided a breakdown of labor and non-labor costs which are related to HCEI initiatives which the Company has current cost estimates. The following table is a summary of the additional test year costs from HECO T-1 Rate Case Update, Attachment 4.

[1] See HECO Companies letter to the Commission, filed November 28, 2008, Docket No. 2007-0416, which informed the Commission that the HECO Companies and the Consumer Advocate agreed that the proposed REIP Surcharge in the REIP proceeding is substantially similar to the CEIS included in the Energy Agreement and that the REIP Surcharge proposal pending before the Commission satisfies the Energy Agreement provision for a CEIS recovery mechanism.
[2] HECO Companies AMI Application, Docket No. 2008-0303, filed December 1, 2008.

(Figures in Thousand's $)

Description (as Shown on Attachment 4 to HECO T-1 Rate Case Update)	HCEI Related Labor	HCEI Related Non-Labor	Recovery via Surcharge
Big Wind Study			2,220
Renewable Energy Power Purchase Division	161	144	
Renewable Energy Planning Division	149	105	
Photo Voltaic Engineer	33		
Project Manager, Power Supply Engineering	84		
HCEI Biofuels Outside Engineering		50	
HCEI Solar Outside Services		200	
AMI Management Consultant		80	
Director, Special Projects	72		
Lead Corporate Accountant	63		
Senior Financial Analyst	52		
Senior Rate Analyst	76		
Energy Projects – Engineer #1	4		
Consultant Cost for Decoupling Docket		200[3]	
Consultant Cost for Feed-in Tariff Docket		230[4]	
Subtotal	649	1,009	2,220

In the course of discovery through information requests responses, and settlement discussions with the Consumer Advocate and the Department of Defense ("DOD"), who are parties to the HECO 2009 test year rate case, the following additional costs were identified as HECI related costs:

[3] $40,000 was allocated to HELCO and MECO and the remaining $160,000 amortized over two years for HECO's 2009 rate case purposes.
[4] $230,000 was amortized over two years for HECO's 2009 rate case purposes.

(Figures in Thousand's $)

Description (as Shown on Settlement Agreement filed May 15, 2009[5])	HCEI Related Labor	HCEI Related Non-Labor	Recovery via Surcharge
Biofuel Agriculture Crop		50	
Biofuel Co-firing Project		649	
Oahu Electric System Analysis			677
AMI T&D Outside Services		507	
AMI R&D		611	
Clean Energy Scenario Planning[6]	484	669	
Office Lease[7]		206	
Subtotal	484	2,692	677
Total Identified in HECO 2009 Rate Case	1,133	3,701	2,897

In the HECO Companies' AMI application, filed December 1, 2008, Docket No. 2008-0303, Exhibit 19 quantified the estimated costs for this project as follows:

(Figures in Thousand's $)

Company	2010	2011	2012	2013	2014	2015	Total
HECO	6,577	20,872	18,471	18,108	2,883	3,352	70,263
HELCO	1,559	1,333	706	721	12,927	1,175	18,421
MECO	1,787	1,506	746	422	640	16,579	21,680
Total	9,923	23,711	19,923	19,925	16,450	21,106	110,364

The above costs include project management (internal HECO Companies labor and non-labor expenses), meters, MDMS (Meter Data Management System), and networking costs. The

[5] Unless otherwise noted, these additional identified costs as related to the Energy Agreement are included in the Parties' Settlement Agreement, filed May 15, 2009, in Docket No. 2008-0083.
[6] This is a transition from the previous Integrated Resources Planning labor and non-labor expenses. In the HECO 2009 test year rate case, Docket No. 2008-0083, the Company, in response to CA-IR-333 and 408, maintained that it is reasonable to assume the resources required for the Clean Energy Scenario Planning in the Energy Agreement (see section 33, pages 37 to 41) would be at the minimum be the same as required for the Integrated Resources Planning, which was discontinued per Commission Decision and Order filed November 26, 2008, Docket No. 2007-0084. See also HECO-1028 which provides the cost breakdown.
[7] This amount represents two new leases' square footage attributed to HCEI initiatives as identified in response to CA-IR-345 (revised 3/31/09), and applying these percentages to the 445/461 Cooke Street lease and CPP 21st Floor lease's "annualized" lease payments as stated in HECO's response to CA-IR-344 (revised 3/31/09). For the 445/461 Cooke Street lease, the amount is 61% x $251,000 = $153,000. For the CPP 21st Floor lease, the amount is 20% x $267,000 = $53,000. These two add up to $206,000.

above referenced Exhibit 19 provides further details on the composition of these costs. The final determination of what costs should be recovered via the AMI Surcharge, REIP Surcharge (if any), and in base rates or through other mechanisms, will depend on the final decision and order in this docket. As such, the HECO Companies are unable to quantify the surcharge versus base rate recoveries for these costs as this time.

Lifeline Rate Program

Lastly, the HECO Companies filed their Lifeline Rate Program with the Commission on April 30, 2009, in Docket No. 2009-0096. Lifeline Rate Program is included in the Energy Agreement in Section 20, page 29. It provides a monthly bill credit to participating low income households, with cost recovery via a Lifeline Rate Adjustment to all residential and non-residential ratepayers.

In their application, the HECO Companies identified the following Lifeline Rate Program costs.[8]

(Figures in Thousand's $)

Company	Annual Bill Credit (Lower Estimate)	Annual Bill Credit (Higher Estimate)	Incremental HECO Companies Labor and Non-Labor Costs
HECO	1,002	4,020	TBD
HELCO	550	3,486	TBD
MECO	216	1,566	TBD
Total	1,768	9,072	TBD

As stated in their application, as the level of participation and complexity of administrative and customer handling requirements are unknown at this time, after one year of

[8] HECO Companies' Lifeline Rate Program Application at 8, 11, and Exhibit C, Docket No. 2009-0096, filed April 30, 2009.

program implementation, the HECO Companies will determine whether any incremental labor and non-labor costs should be recovered in base rates, in the Lifeline Rate Program Adjustment, or via the Revenue Balancing Account ("RBA") in the decoupling docket, Docket No. 2008-0274.

To reiterate, the above costs are those costs which the HECO Companies have identified currently as related to the Energy Agreement, for HCEI initiatives where cost estimates are available at the present time. Where the parties in the applicable docket have agreed to surcharge versus base rate recovery, these have been identified. However, as all of the above dockets are still pending final Commission decision and order, the extent to which costs are to be recovered via surcharge (and which surcharge) versus base rate are still unconfirmed at the present time. Additionally, these expenses are tied to the developmental and implementation timelines of these projects and will increase in the later years until these projects are completed.

PUC-IR-30

In reference to DBEDT's Opening Statement of Position, filed on March 30, 2009, how are the RAM's increased revenues linked to the HECO Companies' compliance with RPS or other renewable goals?

HECO Response:

In the HECO Companies and the Consumer Advocate's joint final statement of position ("Joint Final SOP"), filed May 11, 2009, this issue is addressed in Exhibit E, which maintained that "The imposition of the performance metrics as a condition of initial approval of decoupling, as recommended by DBEDT, Blue Planet, and HREA is unreasonable and unnecessary."[1] The Joint Final SOP points out that (1) certain programs and measures are outside the control of the HECO Companies, (2) the HECO Companies agreed that the Renewable Portfolio Standard ("RPS") is an effective structure to track the Companies' obligation to add renewable energy, (3) there are existing mechanisms in the Energy Agreement which are reinforced in the Joint Proposal on Decoupling ("Joint Proposal") and the HECO Companies and the Consumer Advocate's Joint Final SOP to ensure that the RAM will be reviewed so that it is "operating in the interest of the ratepayers, and (4) tying performance metrics to the RAM is inconsistent with the purpose of the decoupling provision, as reflected in the Energy Agreement."[2]

The Joint SOP suggested an alternative by offering a reporting mechanism as follows:

> However, as a means of resolving this issue with the other parties in the instant proceeding, the Consumer Advocate proposed in the April 20, 2009 technical workshop, and the Companies have agreed to provide a detailed report on the status of HCEI initiatives such as New Net Energy Metering (MW and customers), the amount of New Renewable Energy purchased under the Feed-in-Tariff ("FIT") (MW or kWh) when effective, the increase in other renewable/nonfossil-based energy generation (MW or kWh), ("HCEI Status

[1] HECO Companies and Consumer Advocate Joint Final Statement of Position, filed May 11, 2009, Docket No. 2008-0274, Exhibit E at 1.
[2] Ibid at 2-3.

Report") as part of its testimony and exhibits in the next cycle of rate cases. This performance reporting will be timely and relevant in the proceedings where the Commission will determine if the decoupling mechanism and its RBA or RAM elements should be continued, modified, or terminated. The Companies have also agreed to explicitly include language in the RAM tariff provision memorializing their commitment to provide the HCEI Status Report in the next rate case cycle. See Exhibit B to *Joint Final Statement of Position*, page 1.[3]

[3] Ibid at 3.

PUC-IR-31

Please refer to your response to PUC-IR-17. Is the following summary correct? If not, please explain.

Change from total sales decoupling	States where currently in place
Hybrid RAM	NY, OR (capital cost exempted; O&M escalated on a per customer basis)
All Forecast RAMs	CA, NY
Inflation Only RAMs	none
Full Indexing	CA
Revenue Per Customer Freezes	AR, CO, ID, IL, IN, MD, NC, NJ, NY, OH, OR, UT, VA, WA, WI
SFV	GA, MO, ND, OR

HECO Response:

The table below summarizes all current SFV decoupling plans and rate plans with revenue adjustment mechanisms (RAMs) that we are aware of.

ALL GAS & ELECTRIC PLANS	
Basic Approach	**Jurisdictions Where Currently in Place**
Hybrid RAM – California Style	VT[1], BC (British Columbia, Canada)
Hybrid RAM – British Style	Australia, Britain
All Forecast RAM	CA, CT , NY, VT[1]
Full Indexing RAM	ON (Ontario, Canada), VT[1]
Inflation Only RAM	None
RPC Freeze RAM	AR, CO, FL, ID, IL, IN, MD, NC, NJ, NY, OR, UT, VA, WA, WI
SFV Rate Design	GA, MO, ND, OH

[1]Vermont has revenue cap rate plans but not formal decoupling.

Here is the analogous table for all current *electric* plans. Please note that the majority of

ELECTRIC PLANS ONLY	
Basic Approach	**Jurisdictions Where Currently in Place**
Hybrid RAM – California Style	
Hybrid RAM – British Style	Australia, Britain
All Forecast RAM	CA, CT , NY, VT [1]
Full Indexing RAM	VT[1]
Inflation Only RAM	None
RPC Freeze RAM	ID, MD, OR, WI

jurisdictions use approaches to RAM design that permit attrition relief for input price inflation as well as customer growth.

It can also be seen that no California electric utility currently has a "California-style" hybrid RAM, such as the one the HECO Companies are proposing. Southern California Edison recently proposed such a hybrid RAM, but the RAM ultimately approved had an all-forecast "stairstep" character. This reflects in part the fact that stairstep plans are in force for the other three large California energy utilities. The HECO Companies believe that the move to stairsteps reflects the accumulating experience of the California regulatory community with alternatives to traditional cost of service regulation. California continues to use hybrid RAMs in the regulation of water utilities.

PUC-IR-32

Please estimate the incremental cost of serving an additional customer, by class, and provide the supporting calculations for this estimate

HECO Response:

The HECO Companies do not currently estimate the incremental cost of serving an additional customer. However, in past rate cases, the HECO Companies have estimated a marginal customer cost: see Attachment 1 of this response for the estimated marginal customer cost by rate class in the HECO TY 2005 rate case (in 2003 dollars), in the HELCO TY 2000 rate case (in 2000 dollars), and in the MECO TY 1999 rate case (for Maui Division only in 1999 dollars). The HECO Companies provided these marginal customer cost estimates in these rate cases but did not base any rates or rate design on these estimated marginal customer costs.

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113, TEST-YEAR 2005
MARGINAL COST STUDY
DETERMINATION OF CUSTOMER-RELATED UNIT COSTS

	Schedule R	Schedule G	Schedule J	Schedule H	Schedule PS	Schedule PP	Schedule PT	Schedule F Metered	Schedule F Unmetered
					(2005 $)				
Meter Investment	$86.00	$131.00	$1,297.00	$168.00	$1,029.00	$4,242.00	$28,765.00	$320.00	$0.00
With General Plant Loading (1) x 1.1037	$94.92	$144.58	$1,431.50	$185.42	$1,135.71	$4,681.90	$31,747.93	$353.18	$0.00
Annual Economic Charge Related to Capital Investment	9.91%	9.91%	9.91%	9.91%	9.91%	9.91%	9.91%	9.91%	9.91%
A&G Loading	0.43%	0.43%	0.43%	0.43%	0.43%	0.43%	0.43%	0.43%	0.43%
Total (3) + (4)	10.34%	10.34%	10.34%	10.34%	10.34%	10.34%	10.34%	10.34%	10.34%
Annualized Costs (2) x (5)	$9.81	$14.95	$148.02	$19.17	$117.43	$484.11	$3,282.74	$36.52	$0.00
Services Investment	$288.00	$308.00	$813.00	$324.00	$800.00	$1,006.00	$9,910.00	$478.00	$478.00
With General Plant Loading (7) x 1.1037	$317.87	$339.94	$897.31	$357.60	$882.22	$1,110.32	$10,937.67	$527.57	$527.57
Annual Economic Charge Related to Capital Investment	9.91%	9.91%	9.91%	9.91%	9.91%	9.91%	9.91%	9.91%	9.91%
A&G Loading	0.43%	0.43%	0.43%	0.43%	0.43%	0.43%	0.43%	0.43%	0.43%
Total (9) + (10)	10.34%	10.34%	10.34%	10.34%	10.34%	10.34%	10.34%	10.34%	10.34%
Annualized Costs (8) x (11)	$32.87	$35.15	$92.78	$36.98	$88.47	$114.81	$1,131.15	$54.55	$54.55
Meter O&M Expenses	$8.77	$8.77	$87.01	$11.25	$88.07	$284.43	$1,829.86	$21.46	$5.77
Service O&M Expenses	$5.84	$6.25	$18.47	$6.80	$12.16	$20.36	$300.85	$0.00	$0.00
Customer Service and Informational and Sales Expenses	$35.19	$47.35	$80.34	$46.87	$88.90	$58.19	$55.95	[illegible]	$0.00
With A&G Loading [(13)+(14)+(15)] x 1.6173	80.54	100.86	304.84	104.84	223.38	588.03	3536.49	123.26	9.33
Customer-Related Cost (6) + (12) + (16)	123.22	150.99	605.74	160.99	409.28	1187.97	7950.38	214.33	63.88
Working Capital									
Materials and Supplies [(2)+(8)] x 0.57%	2.35	2.76	13.27	3.10	10.25	33.02	243.31	5.02	3.01
Prepayments [(2)+(8)] x 0.12%	0.50	0.58	2.79	0.65	2.16	6.95	51.22	1.06	0.63
Cash Working Capital (16) x 6.78%	5.46	6.84	17.81	7.09	15.10	39.87	239.07	8.33	0.63
Revenue Requirement for Working Capital [(18)+(19)+(20)] x 13.24%	1.10	1.35	4.80	1.44	3.64	10.57	70.67	1.91	0.57
Total Customer-Related Costs (17) + (21)	124.32	152.32	610.24	162.42	412.92	1198.53	8021.03	216.24	64.46
Total Marginal Cost (Rounded)	$124	$152	$610	$162	$413	$1,199	$8,021	$216	$64

ICMFP2.

FILE: CUSTSUM

HAWAII ELECTRIC LIGHT COMPANY, INC.
COMPUTATION OF CUSTOMER-RELATED UNIT COSTS

		Residential (Secondary Service)	General (Non Demand Service)	General (Demand Service)	Commercial Cooking, Heating, etc	Industrial (Large Power)	Public & Street Lighting (Metered)	(Unmetered)
		(2000 Dollars Per Customer)						
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
(1)	Meter Investment	$246.54	$246.54	$4,519.82	$976.66	$12,875.70	$246.54	$0.00
(2)	With General Plant Loading (1) x 1.0785	$265.89	$265.89	$4,874.63	$1,053.33	$13,886.44	$265.89	$0.00
(3)	Annual Economic Charge Related to Capital Investment	9.17%	9.17%	9.17%	9.17%	9.17%	9.17%	9.17%
(4)	A&G Loading	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%
(5)	Total (3) + (4)	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%
(6)	Annualized Costs (2) x (5)	$25.58	$25.58	$468.94	$101.33	$1,335.88	$25.58	$0.00
(7)	Services Investment	$667.96	$838.64	$1,617.23	$1,423.38	$3,098.55	$319.23	$0.00
(8)	With General Plant Loading (7) x 1.0785	$720.40	$904.48	$1,744.18	$1,535.11	$3,341.79	$344.29	$0.00
(9)	Annual Economic Charge Related to Capital Investment	9.17%	9.17%	9.17%	9.17%	9.17%	9.17%	9.17%
(10)	A&G Loading	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%
(11)	Total (9) + (10)	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%
(12)	Annualized Costs (8) x (11)	$69.30	$87.01	$167.79	$147.68	$321.48	$33.12	$0.00
(13)	Meter O&M Expenses	$9.75	$16.29	$176.58	$53.82	$361.95	$9.75	$0.00
(14)	Service O&M Expenses	$2.42	$3.51	$5.84	$4.26	$9.93	$2.42	$2.42
(15)	Customer Accounts, Customer Service and Informational and Sales Expenses	$56.72	$62.35	$95.52	$66.31	$114.63	$61.63	$61.63
(16)	With A&G Loading [(13)+(14)+(15)] x 1.4361	98.93	117.98	399.15	178.64	698.67	105.98	91.98
(17)	Customer-Related Cost (6) + (12) + (16)	193.81	230.57	1035.88	427.65	2356.03	164.68	91.98
	Working Capital							
(18)	Materials and Supplies [(2)+(8)] x 0.79%^1	7.79	9.25	52.29	20.45	136.10	4.82	0.00
(19)	Prepayments [(2)+(8)] x 0.05%^1	0.49	0.59	3.31	1.29	8.61	0.31	0.00
(20)	Cash Working Capital (16) x -0.82%^2	-0.81	-0.97	-3.28	-1.47	-5.74	-0.87	-0.76
(21)	Revenue Requirement for Working Capital [(18)+(19)+(20)] x 13.25% ^3	0.99	1.17	6.93	2.69	18.41	0.56	-0.10
(22)	Total Customer-Related Costs (17) + (21)	194.80	231.74	1042.81	430.33	2374.44	165.25	91.88
(23)	Total Marginal Cost (Rounded)	$195	$232	$1,043	$430	$2,374	$165	$92

FILE: CUSTSUM

MAUI ELECTRIC COMPANY, LIMITED
COMPUTATION OF CUSTOMER-RELATED UNIT COSTS
Maui Division 1999

		Residential (Secondary Service)	General (Non Demand Service)	General (Demand Service)	Commercial Cooking, Heating, etc.	Industrial (Large Power)	Public & Street Lighting (Metered)	Public & Street Lighting (Unmetered)
		(1999 Dollars Per Customer)						
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
(1)	Meter Investment	$101.98	$211.63	$366.24	$282.91	$1,847.67	$163.38	$0.00
(2)	With General Plant Loading (1) x 1.0479	$106.86	$221.76	$383.77	$296.44	$1,936.08	$171.20	$0.00
(3)	Annual Economic Charge Related to Capital Investment	9.39%	9.39%	9.39%	9.39%	9.39%	9.39%	9.39%
(4)	A&G Loading	0.54%	0.54%	0.54%	0.54%	0.54%	0.54%	0.54%
(5)	Total (3) + (4)	9.93%	9.93%	9.93%	9.93%	9.93%	9.93%	9.93%
(6)	Annualized Costs (2) x (5)	$10.61	$22.02	$38.11	$29.44	$192.25	$17.00	$0.00
(7)	Services Investment	$235.76	$288.39	$364.44	$346.51	$1,066.93	$235.76	$248.17
(8)	With General Plant Loading (7) x 1.0479	$247.04	$302.19	$381.88	$363.09	$1,117.99	$247.04	$260.05
(9)	Annual Economic Charge Related to Capital Investment	9.39%	9.39%	9.39%	9.39%	9.39%	9.39%	9.39%
(10)	A&G Loading	0.54%	0.54%	0.54%	0.54%	0.54%	0.54%	0.54%
(11)	Total (9) + (10)	9.93%	9.93%	9.93%	9.93%	9.93%	9.93%	9.93%
(12)	Annualized Costs (8) x (11)	$24.53	$30.01	$37.92	$36.06	$111.03	$24.53	$25.83
(13)	Meter O&M Expenses	$12.35	$25.44	$44.08	$34.08	$222.63	$12.35	$0.00
(14)	Service O&M Expenses	$1.88	$2.30	$3.00	$2.77	$8.52	$1.88	$1.88
(15)	Customer Accounts, Customer Service and Informational and Sales Expenses	$44.33	$60.50	$107.85	$61.22	$136.83	$39.25	$39.25
(16)	With A&G Loading [(13)+(14)+(15)] x 1.4331	83.93	126.45	222.03	140.55	527.37	76.65	58.96
(17)	Customer-Related Cost (6) + (12) + (16)	119.07	178.48	298.06	206.04	830.65	118.19	84.78
	Working Capital							
(18)	Materials and Supplies [(2)+(8)] x 2.87%^1	10.14	15.02	21.94	18.90	87.53	11.99	7.45
(19)	Prepayments [(2)+(8)] x 0.06%^1	0.21	0.31	0.46	0.40	1.83	0.25	0.16
(20)	Cash Working Capital (16) x 0.07%^2	0.06	0.09	0.15	0.10	0.37	0.05	0.04
(21)	Revenue Requirement for Working Capital [(18)+(19)+(20)] x 13.38% ^3	1.39	2.06	3.02	2.60	12.01	1.64	1.02
(22)	Total Customer-Related Costs (17) + (21)	120.46	180.54	301.08	208.64	842.66	119.83	85.80
(23)	Total Marginal Cost (Rounded)	$120	$181	$301	$209	$843	$120	$86

SOURCE:	Lines (1),(7):	Based on typical installed costs. See worksheet (MTR&SERV).
	Lines (2),(8):	See workpaper for General Plant Loading Factor.
	Lines (3),(9):	See workpaper for Economic Carrying Charge.
	Lines (4),(10):	See workpaper for A&G Loading Factor.
	Line (13):	See workpaper for "Meter O&M Expenses by Customer Class" (MTRO&MP2).
	Line (14):	See workpaper for "Service O&M Expenses by Customer Class" (SERO&MP2).
	Line (15):	See workpaper for "Customer Accounts Expenses by Customer Class" (CUSACCP2) and "Customer Service and Information Expenses by Customer Class" (SVCINFP2).
	Lines (18),(19):	See workpaper for Materials & supplies, and Prepayments Loading Factors (M&S&PRE).

PUC-IR-36

In your response to PUC-IR-6, the HECO Companies state that attachment 15A.2 from the HECO Companies' Revenue Decoupling Proposal, filed on January 30, 2009, is for "illustrative purposes only." Should the Commission consider these and other examples (such as those in response to PUC-IR-14 and 15) to be illustrative, or the HECO Companies' best estimates of the effect of the HECO Companies' decoupling and RAM proposals?

HECO Response:

The Commission should consider the attachments noted above in the information request to be illustrative, given changes that have occurred since the time that these documents have been filed. For MECO and HELCO, the last calculations for the Operating & Maintenance Expense ("O&M") Revenue Adjustment Mechanism ("RAM") and the Rate Base RAM were made using the assumptions reflected in the Companies' initial "HECO Companies' Revenue Decoupling Proposal", filed January 30, 2009, that have since been revised with the HECO Companies' decoupling agreement with the Consumer Advocate (see Joint Final Statement of Position of the HECO Companies and Consumer Advocate, filed May 11, 2009, Exhibit C ("FSOP")). Even the HECO O&M and Rate Base RAM, filed as Attachments 1 and 2 of Exhibit C in the FSOP, is outdated due to the change in its test year estimate which served as the "base" for the 2010 RAM estimate. HECO is scheduled to file its Statement of Probable Entitlement for its 2009 rate case on May 18, 2009, the day that the Companies are filing this response, based on its settlement with the other parties in that proceeding, which significantly reduced HECO's requested interim amount from its rate case update amount. This reduction would, in turn, impact HECO's RAM estimate for 2010 and beyond.

As stated in their response to PUC-IR-14, the spreadsheets submitted were "strictly for illustrative purposes" and were based on the methodology proposed by the Companies in their initial proposal that was filed on January 30, 2009, and other assumptions stated in the response. As a result, the Commission should not consider the estimates as the HECO Companies' current best estimates for decoupling and the RAM adjustments.

PUC-IR-37

In response to PUC-IR-2, the HECO Companies dismiss the need for service quality targets as part of a decoupling initiative. Please discuss service quality targets that have been used as part of price or revenue cap regulatory paradigms (e.g., Massachusetts).

HECO Response:

In its response to PUC-IR-2, HECO stated that a utility's service quality is most likely to be jeopardized when real profits are to be made, and that these profit opportunities depend chiefly on the length of time between rate cases. Since the proposed interval between rate cases is three years in the Joint Final Statement of Position[1] (which is shorter than the four years normally considered under performance-based regulation to provide cost containment incentives sufficiently strong to warrant quality concerns) HECO responded that the "introduction of service quality standards therefore appears to the HECO Companies to be an unnecessary complication. If standards are introduced, the HECO Companies recommend starting with a service quality monitoring program that does not involve awards or penalties."

The great majority of utilities operating under revenue decoupling mechanisms do not operate, additionally, under service quality ("SQ") programs that mechanistically link award and/or penalty to comparisons of SQ indicators to certain standards. The popularity of revenue per customer freezes amongst gas utilities is one reason for this, since this kind of RAM does not provide enough attrition relief to permit most utilities to agree to rate case moratoria that would strengthen incentives for cost containment sufficiently to raise concerns about quality degradation.

[1] The Consumer Advocate and the HECO Companies are not proposing price cap regulation. Instead, they are proposing sales decoupling and a revenue adjustment mechanism.

If we turn our attention to utilities operating under multiyear rate or revenue caps, there is greater use of SQ award and/or penalty mechanisms ("APMs"), as we would expect, but this is due in large measure to the fact that most of these caps have terms that are longer than the two or three years that we propose in the HECO Companies and the Consumer Advocate's Joint Final SOP, filed May 11, 2009. To the best of the Companies' knowledge, less than half of ALL multiyear rate or revenue cap plans for electric utilities have featured service quality APMs. Moreover, the prevalence of APMs is much higher for plans with terms exceeding three years than it is for plans with two or three-year terms. The average term of rate and revenue cap plans with APMs is well in excess of four years.

Some commissions have established standards for SQ indicators but not APMs. Others monitor SQ indicators without establishing standards or APMs. Quite a few commissions do not routinely monitor SQ indicators. Massachusetts is a good example of a jurisdiction where a penchant for lengthy plan terms has encouraged the institution of APMs. Five of seven larger utilities in the Commonwealth operate under multiyear rate plans. The average term of these plans is more than seven years.

The indicators featured in service quality APMs for electric utilities commonly include reliability metrics. The system average interruption duration index ("SAIDI") and the system average interruption frequency index ("SAIFI") are most commonly used for this purpose, but the customer average interruption duration index ("CAIDI") and the momentary average interruption frequency index ("MAIFI") are also used. Indicators for customer care service quality are also common. The corresponding standards are usually utility-specific and reflect the utility's historically reported values for the indicators.

The indicators employed in Massachusetts, chosen in a generic proceeding, are illustrative of the possibilities. These are:

SAIDI;
SAIFI;
On-cycle meter reads;
Timely call answering;
Percent of service appointments met;
Complaints to regulators;
Billing adjustments;
Lost work time accidents.

PUC-IR-38

Is the following a complete list of the changes made to the HECO Companies' original proposal and now included in the joint proposal with the Consumer Advocate? If not, please explain.

a. The inclusion of an asymmetric earnings-sharing method;
b. The use of two indices, the GDPPI for non-labor and the labor contract rate for labor;
c. A 0.76% productivity adjustment on labor costs;
d. Using a 6% interest rate on over and under collections;
e. Review period - file decoupling and RAM adjustments based on previous historical year's actual data by 2/28, with rate changes commencing 5/1;
f. Exclude investments other than plant additions from the RAM rate base adjustment (e.g., exclude CIS, AMI, inventory, cash working capital).

HECO Response:

The items that have changed from the HECO Companies' original proposal and the most current joint proposal made by the Consumer Advocate and the Companies may be found in Exhibit C, filed as part of the *Joint Final Statement of Position of the HECO Companies and Consumer Advocate* ("FSOP") on May 11, 2009, in the instant proceeding.

Of the list of items presented above in the information request, two items have been revised from the *Joint Proposal on Decoupling and Statement of Position of the HECO Companies and the Consumer Advocate*, filed on March 30, 2009. Item e, "Review period," has been revised for the RBA and RAM annual filings to take place on March 31 and associated rate changes to become effective on June 1. Item f which addresses the RAM rate base adjustment, is now based on the Consumer Advocate's initially proposed methodology which was presented in detail by the Consumer Advocate in the Technical Workshop held on February 27, 2009. The RAM rate base adjustment was further refined and presented in the Technical Workshop held on April 20, 2009, and is included as Attachment 2 of Exhibit C of the FSOP. This methodology and its associated data requirements and calculations are very different from that initially proposed by the HECO Companies.